Guidelines for Distributed Utility Planning ("DUP")

In the planning process, the utility has an obligation to:

- Design its transmission and distribution ("T&D") system to meet expected normal loads.
- Design its T&D system to meet first-contingency loads, where justified and feasible, given the density and spatial distribution of load.
- Where T&D supply problems are experienced or projected,
  - * analyze alternatives at a level of detail commensurate with the scale of the problems and the costs of proposed solutions.
  - * re-configure the system to meet loads at the lowest feasible cost before any equipment upgrades are contemplated.
  - * seek the combination of DSM,[1] distributed generation ("DG"), and traditional T&D investments that solves the problem at the lowest net cost, considering all costs, benefits and risks.

These guidelines are intended to apply to the resolution of T&D supply problems and discuss the last point above: the process for including DSM and distributed generation in the T&D planning process to reduce the cost of maintaining the reliability, stability, safety, and quality of power delivery.

1. Identify areas with existing or projected T&D supply problems (*i.e.*, capacity-constrained areas).

   a) Identify areas (usually defined by substation or feeder number) in which major T&D investments are planned or projected to solve a T&D supply problem. Emerging problems should be identified as long in advance as practicable, to identify as many situations as possible in which intensified, targeted DSM and distributed

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[1] In these Guidelines, demand-side management ("DSM") includes actions that reduce consumer requirements for electric T&D service, including efficiency, fuel choice and load control measures (which may include special contracts and other rate-design features).

generation may be helpful, while those strategies have sufficient lead time to be effective.

b) Determine whether the problem identified in 1.a) above would be avoided or deferred, or the cost of resolving it would be reduced, by reductions in load. If not, DUP is not applicable.

c) Identify the Critical Element(s): the feeder, substation, and/or transmission line expected to be overloaded in the absence of T&D reinforcement.[2]

2. Define the region in which load reductions would be reasonably expected to contribute to deferring or avoiding the need for the T&D reinforcement, or otherwise reducing the cost of resolving the problem identified in 1.a) above.

   a) This DUP region includes both areas served by the Critical Element and areas served by other T&D facilities to which load can be transferred from the Critical Element (subject to normal engineering guidelines).[3]

   b) If the Critical Element is a feeder, the DUP region includes the area served by the feeder and its laterals or taps, and potentially

      i) parallel feeders close to laterals or taps that run from the Critical Element.

      ii) feeders that are connected to the Critical Element through a normally open switch.

   c) If the Critical Element is a distribution substation, the potential DUP region includes

      i) the area normally served by the feeders from that substation;

[2] Due to reconfiguration and ability to share loads, as well as the possibility of overloads at multiple voltage levels, a particular problem area may have several Critical Elements.

[3] The extent of reconfiguration of the distribution system may be limited by reliability, stability, operational, safety or cost considerations.

ii) the entire area normally served by other substations serving feeders that can take load off the feeders served by the Critical Element in either of the ways described above.

d) If the Critical Element is a transmission line (or substation), the potential DUP region includes

i) the area downstream from the Critical Element,[4] and

ii) the area served by any transmission line (or substation) that can pick up load from the Critical Element

a) directly by serving a distribution substation currently downstream of the Critical Element, or

b) indirectly by transfer of feeder loads from substations on the Critical Element to substations on the alternative line.

e) If the critical load is a first-contingency overload, include in the relevant area all of the circuits that contribute to a first-contingency overload on the Critical Element. In particular, consider:

i) All feeders connected to the end of Critical Element through a normally open switch,

ii) All feeders parallel to the Critical Element, and

iii) All feeders parallel to feeders connected to the end of the Critical Element through a normally open switch.

f) Include other utilities' facilities in assessing options for the incumbent utility to serve its customers' loads at societal least cost.[5]

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[4] For transmission lines served at both ends, "downstream" is defined for the conditions creating the critical load.

[5] The purpose of DUP is to allow the utility to continue to serve its customers and its service territory at the minimum cost to society. Each utility is responsible for conducting DUP to minimize the costs of resolving supply problems on its own system, as well as the costs of resolutions for which the utility will be charged. Each utility will have a duty to consult and cooperate reasonably with requests of other utilities to take measures to solve

i) Consider supply options that use the substations and feeders of other utilities, where available.

ii) Coordinate targeted DSM with adjacent utilities as an option for reducing loads on the Critical Element.

3. Identify deferrable costs and the load reductions that would be needed to defer those costs for various periods of time.[6]

a) Specify the magnitude, shape, and timing of the load reduction necessary to avoid T&D expenditures over the identified time periods.

i) Use the relevant load forecast on which project planning is based.[7]

ii) Determine which peaks and other high load hours are expected to affect the overloading problem.[8]

b) Include all reasonably foreseeable effects of load reductions on T&D timing. With continuous load growth, additional elements, especially at different voltage levels may become overloaded over time.

4. Compute the benefits of DSM load reductions:

T&D problems on the other utilities' systems, with costs equitably allocated to the utility whose customers cause the need for, or receive the benefits of, measures to be taken. The utility seeking cooperation should petition the Board in the event that another utility is not fulfilling its duty to cooperate reasonably.

[6] Load reductions may be able to avoid the T&D project permanently or delay it, depending upon the pattern of load growth and the regional DG and DSM potential. With continuous load growth, longer deferrals will require larger load reductions in each succeeding year.

[7] Where load growth is highly uncertain, incorporating relevant annual load projections and sensitivity analysis around those projections may more meaningfully identify when actions are required than a single forecast.

[8] Timing of peaks may vary between portions of the DUP region.

a) In cases where the entire T&D expenditure is avoided, determine the total present value revenue requirements (PVRR) including O&M and net of any change in losses.[9]

b) In cases where the T&D expenditure is deferred, determine the value of delaying the project one year (the capital investment times the real-levelized carrying charge, plus O&M, net of any change in losses).

c) Using (b), compute the total present value of cost deferral as a function of the number of years of deferral.

d) To the DUP-region T&D value, add the value of avoided energy, avoided generation capacity (with any required reserve margin), and residual T&D (defined below).[10] Include all benefits of load reductions, regardless of whether the reductions are coincident with the loads that drive the T&D expansion.

5. Seek targeted DSM retrofit, enhanced lost-opportunity programs, and distributed generation to relieve congestion.

a) Attempt to construct packages of DSM and DG with sufficient scale and acceptable costs.[11]

b) The potential for DSM retrofit programs depends on the installed mix of end uses, and on the lead time required to implement the programs.

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[9] The costs of the T&D expansion should be adjusted to reflect any associated benefits.

[10] The benefits of load reduction should be adjusted to reflect the effects of T&D system re-configuration on losses or other costs.

[11] As agreed upon in the Docket 5980 MOU, paragraph 35: "A DU shall be required to ensure that DSM implementation undertaken as part of DUP is conducted in a manner that does not create lost opportunities, including but not limited to lost opportunities in the market segments targeted by the Core Programs, and appropriately inventories future potential savings. The Parties agree that DUP does not require a DU to secure DSM savings beyond those that will enable it to fulfill the DU's DUP planning and implementation responsibilities."

c) The potential for market-driven programs depends on the rate at which the underlying events (e.g., new construction) occur. Estimates of this potential will generally be driven by the same factors to lead to the expectation of T&D constraints.[12]

d) Use the relevant load forecast on which T&D Plans are based to forecast DSM potential.[13] Where load growth is highly uncertain, incorporating relevant annual load projections and sensitivity analysis around those projections may more meaningfully identify when actions are required than a single forecast.

6. Compute appropriate residual non-DUP-region T&D benefits resulting from reductions in load growth.

7. Select from among the available options (new T&D investment, DSM, and/or DG, with various levels of reconfiguration and use of other utilities' facilities) based on minimizing net societal costs, reflecting any of the following that are significant:[14]

a) The avoided costs described above.

b) Customer and utility expenditures and savings.

c) Changes in losses due to DSM, DG, and T&D alternatives.

d) Any costs of integrating DG into to the distribution system.

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[12] Distribution utilities may rely on the Energy Efficiency Utility for the estimation of potential from enhancements of the market-driven and other core statewide programs.

[13] Recognize that some uncertainties are associated with DSM potential estimates. It may be useful to forecast a DSM potential estimate for each load forecast discussed in footnote 7, above.

[14] As agreed upon in the Docket 5980 Memorandum of Understanding (paragraph 34): "When considering the cost-effectiveness of alternatives to a new T&D investment, a DU shall choose the optimal investment strategy, determined under the societal test as defined in Docket No. 5270, subject to the constraints that the chosen strategy produces positive electric system net benefits including T&D cost savings, energy and capacity, and that it will enable the DU to operate its electric system in a safe and reliable manner."

e) Any power-quality or reliability benefits of DG or T&D to host facilities.

f) Important case specific differences in system safety, reliability and stability not addressed by interconnection standards or other generic provisions approved by the Vermont Public Service Board.

g) Important differences in environmental and aesthetic effects.

h) Important differences in risk and flexibility, including but not limited to significant risks of stranded T&D, DSM, or DG investment; or the emergence of new technologies.

If the selected option for solving the problem identified in 1.a) above is significantly inferior to one or more alternatives in a manner that cannot be fully monetized (system reliability, stability, environmental effects, aesthetics, risk, flexibility) , the utility should specify the cost or other benefits that outweigh the detriments.

8. Prepare an implementation plan for the selected option.

a) Schedule resource additions to minimize cost, while maintaining flexibility and a high level of assurance that reliable service can be provided with the least-cost plan.

b) Consider ownership, institutional and contractual arrangements (e.g., with the EU, other utilities, large customers, owners or operators) to manage financial and rate effects, to the extent possible, without significantly increasing societal costs or reducing reliability or probability of success.

c) Determination that more than sufficient lead time exists for the preferred option may allow deferral of implementation until uncertainties are resolved and need is more imminent.

d) Consider the hedge potential, and costs to acquire that potential, of each of the following:

i) Identified load-reduction potential from DSM in excess of expected needs;

ii) Identified load-serving potential from a DG resource in excess of expected needs; and

iii) Identified load-serving potential from a T&D facility in excess of expected needs.